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APPENDIX A: ANNEX I AND NON-ANNEX I COUNTRIES

The 1992 Framework Convention on Climate Change stipulated that, among other provisions, a non-binding emissions reduction goal for the industrialized countries of the world. These countries, including most developed countries and the economies in transition of the former Soviet bloc, are identified in the treaty as members of "Annex I". Countries not included in this list are identified as "Non-Annex I". Non-Annex I is composed primarily of developing countries, but also includes the newly industrialized countries of Asia, and two OECD members (Korea and Mexico). In general, Annex I has often been used to refer to industrial countries and Non-Annex I has been used to refer to developing countries.

Under the Kyoto Protocol, the industrialized, or developed countries, that agreed to binding emissions targets are identified as Annex B countries. The list of Annex B countries is virtually identical to the list of Annex I countries (see below).

Annex I Countries under Framework Convention

Australia
Austria
Belarus
Belgium
Bulgaria
Canada
Czechoslovakia
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Iceland
Ireland
Italy
Japan
Latvia
Lithuania
Luxembourg
Netherlands
New Zealand
Norway
Poland
Portugal
Romania
Russian Federation
Spain
Sweden
Switzerland
Turkey
Ukraine
United Kingdom
United States

Annex B Countries under Kyoto Protocol

Australia
Austria
Belgium
Bulgaria
Canada
Croatia
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Iceland
Ireland
Italy
Japan
Latvia
Liechtenstein
Lithuania
Luxembourg
Monaco
Netherlands
New Zealand
Norway
Poland
Portugal
Romania
Russian Federation
Slovakia
Slovenia
Spain
Sweden
Switzerland
Ukraine
United Kingdom
United States

APPENDIX B: CONSTRUCTION OF NON-CARBON DIOXIDE EMISSIONS BASELINES

Emissions of greenhouse gases for countries were drawn from the countries' national communications to the Framework Convention on Climate Change. For some countries' emissions of greenhouse gases in some years, estimates of emissions were not provided. Details of the derivation of these emissions are provided below.

- Australia: Non-CO_2 greenhouse gases comprise 33% of all greenhouse gas emissions in 1990. These are assumed to be 25% of all greenhouse gas emissions in 2010 based on the trends projected in the United States and the European Union. The 1990/95 baseline excludes SF_6 and HFCs.

- Austria: For methane and nitrous oxide, 2010 emissions are based on a linear extrapolation from the projected 2000 level using the projected average annual growth rate over the 1990-2000 period. For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Belgium: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Canada: For non-CO_2 greenhouse gases, Canada is assumed to have the same non-CO_2 emissions/total greenhouse gas emissions ratio as the United States (0.17 in 1990/95 and 0.13 in 2010). Total greenhouse gas emissions are then calculated based on historical and projected CO_2 emissions.

- Denmark: For methane and nitrous oxide, 2010 emissions are based on a linear extrapolation from the projected 2005 level using the projected average annual growth rate over the 2000-2005 period. For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Eastern Europe: For non-CO_2 greenhouse gases, Eastern European countries are assumed to have the same non-CO_2 emissions/total greenhouse gas emissions ratio as the Former Soviet Union (0.25 in 1990/95 and 0.19 in 2010). Total greenhouse gas emissions are then calculated based on historical and projected carbon dioxide emissions.

- Finland: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Former Soviet Union: Non-CO_2 greenhouse gases comprise 25% of all greenhouse gas emissions in 1990. These are assumed to be 19% of all greenhouse gas emissions in 2010 based on the trends projected in the United States and the European Union. The 1990/95 baseline excludes SF_6, PFCs, and HFCs.

- France: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Germany: For methane and nitrous oxide, 2010 emissions are based on a linear extrapolation from the projected 2005 level using the projected average annual growth rate over the 1990-2005 period. For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Greece: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP times the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Ireland: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Italy: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Japan: Non-CO_2 greenhouse gases comprise 4% of all greenhouse gas emissions in 1990. These are assumed to be 3% of all greenhouse gas emissions in 2010 based on the trends projected in the United States and the European Union. The 1990/95 baseline excludes SF_6, PFCs, and HFCs.

- Luxembourg: For methane and nitrous oxide, 2010 emissions are based on a linear extrapolation from the projected 2000 level using the projected average annual growth rate over the 1990-2000 period. For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Portugal: For the three categories of synthetic gases, estimated emissions for 1995 and 2010 are based on multiplying 1995 GDP by the emissions/GDP(1995) average ratios derived from the Netherlands, Sweden, and the United Kingdom.

- Spain: At the time this analysis was conducted, the United Nations had not posted a national communication for Spain on the FCCC webpage. Estimates of the methane and nitrous oxide emissions are based on the average methane/GDP(1995) and nitrous oxide/GDP(1995) ratios for the other 14 E.U. countries multiplied by Spain's 1995 GDP. Similar calculations were done for the three categories of synthetic gases, but only based on the average of emissions from the Netherlands, Sweden, and the United Kingdom.

APPENDIX C: POTENTIAL ELECTRICITY RESTRUCTURING COST-SAVINGS

The Administration's electricity restructuring proposal provides potential cost-savings in four areas: cost reduction (including fuel procurement, non-fuel operation and maintenance [O&M] expenses, and administrative and general [A&G] expenses), dispatch efficiency, improved capital utilization, and savings in capital additions. These four categories of savings are likely to reach or exceed $20 billion annually. Table C1 summarizes these potential savings.

Table C1. Summary of Restructuring Cost-Savings Potential

Source of Savings	Potential Annual Cost-Savings (billions of 1996 dollars)
Cost Reduction (Fuel, non-fuel O&M, A&G)	$24.6
Dispatch Efficiency	$0.6
Improved Capital Utilization	$0.8 to $2.6
Reduced Capital Additions	$0.3 to $3.8
TOTAL	$26.3 to $31.6

Several sources of important additional savings are not considered in this analysis.

- First, as pricing becomes more efficient, load shape adjustments from consumers on the demand side of the meter can reduce the need to add expensive new capacity that would otherwise be necessary to meet peak demands of only a few hours duration per year (e.g., on the hottest summer days). A recent study of the New York State power pool suggests that savings in that one area alone could reach $660 million annually by 2010.

- Second, our cost analysis assumes that regulators and firms would not repeat past mistakes with respect to capacity planning, choice of technology, or project management that have raised the cost of power to consumers. While regulators have undoubtedly learned from past events, future regulation is unlikely to be perfect.

- Finally, experience in other sectors suggests that competition will lead to the creation of new product combinations with greater economic value to consumers. Our estimates do not reflect this benefit at all.

Fuel Costs, Non-Fuel Operation and Maintenance (O&M) Costs, and Administrative and General (A&G) Costs

Fuel Costs, Non-Fuel O&M Costs, and A&G Costs, which together accounted for roughly $94 billion in reported utility costs in 1995, largely reflect the current operations of electric utilities.[1]

Information reported in standard industry filings suggests a wide range of cost experience across reporting units and companies. These data can provide insight into opportunities for cost reduction. Our approach here is to estimate the value of bringing the cost performance of the entire industry up to the standard already demonstrated by top industry performers -- represented in this paper as the average of the top quartile of reported performance.

Some of the differences in cost experience clearly reflect circumstances that will not change under competition. For example, coal prices differ according to the distance from low-cost coal supplies; heat rates reflect the vintage, type, scale, and operating rate of plants and pollution control requirements; and distribution costs are systematically related to the density of customers on a system. To account for such factors, we stratified the reported data along key dimensions prior to developing the quartile analysis. Stratification narrows the range of cost variation, but significant differences remain, as reported in Table C2.

Table C2. Cost-Reduction Opportunities

Category	Potential Annual Cost-Savings (billions of 1996 dollars)
Fuel Acquisition	$6.7
Heat Rates	$0.9
Non-fuel Operation and Maintenance	$11.0
Administrative and General	$6.0
TOTAL	$24.6

The reported total of $24.6 billion in cost-saving potential could either underestimate or overestimate actual cost reduction opportunities. On the underestimation side, top quartile performance under regulation may understate achievable efficiencies under competition as even the best current performers re-engineer and rethink their activities. Moreover, the lack of data for existing non-utility generators, which are

[1] A portion of A&G costs also reflect historical operations to the extent that pension liabilities have not been funded on a current basis.

widely believed to be among the most cost-effective operators, could lead to some underestimation of even the current state-of-the-art efficiencies. On the overestimation side, the stratification underlying the quartiles reported in Table C2 for fuel and O&M costs may fail to account for all sources of irreducible cost differences. Moreover, the portion of the variation in cost across plants that reflects contract cycles for fuel and other inputs could be expected to narrow over time independent of the advent of competition.

Dispatch Efficiencies

Competition likely will result in improved dispatch efficiencies. The advent of competition will shift the market from a "shared savings" paradigm to one in which the party that identifies a cost-effective trade can reap the benefits, providing dispatch efficiencies beyond those that might result from wholesale competition alone. Analyses using the Policy Office Electricity Modeling System (POEMS) suggest that dispatch efficiencies resulting from retail competition can reduce aggregate system fuel costs by approximately $600 million relative to a scenario reflecting a continued cost-of-service regime.

More Efficient Utilization of Capital

The generation, transmission, and distribution of electricity are among the most capital-intensive activities in the United States. Yet, the relatively inflexible price signals provided to consumers under traditional cost-of-service regulation have resulted in relatively poor utilization of our substantial investment in electricity-related capital. Retail competition will allow electricity markets to emulate the experience of airlines and communications providers in implementing load-sensitive pricing regimes,[2] allowing the additional use of electricity in price sensitive applications during off-peak and off-season periods.

Ideally, the gains from more efficient capital utilization would be calculated separately for each load segment in each season. Although data on the segment-specific demand responses to price variation are not available, we can use the impacts of competition on average prices to develop a rough estimate of capital utilization cost-savings. Model results and recent experience with restructuring at the state level suggest that average delivered prices in a restructured industry will be 6 to 9 mills (9 to 13 percent) lower than prices projected under continued cost-of-service regulation, depending upon what provisions are made for stranded cost recovery. Using an

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[2] An example of such a pricing regime can be found in the telecommunications industry where some firms offer lower prices during off-peak times, such as 5 cents per minute calls on Sundays.

estimate of -0.1 to -0.2 for the price elasticity,[3] the 9 to 13 percent price drop translates into an increase of between 0.9 and 2.6 percent in electricity sales.

The net welfare benefit from these extra sales includes two components. First, there is additional "consumer surplus," which reflects the extent to which the value of the extra electricity to buyers exceeds its price. Second, since extra sales under load-sensitive market pricing do not increase transmission or distribution system costs or stranded costs, any transmission, distribution, or stranded cost charges on these sales are also a net welfare gain. In 1995, the national average for transmission and distribution was 2.38¢/Kwh. For a level of baseline demand of 3.25 trillion kilowatt hours, the estimated net welfare gain from more intensive capital utilization is estimated to fall between $820 million and $2.6 billion.

It is important to note again that the estimates in this section focus narrowly on the more efficient use of the baseline capital stock. These estimates do not account for the substantial cost-savings associated with more nimble pricing in curtailing peaks that often necessitate the addition of expensive new capacity.

Reduced Capital Costs at Existing Plants

Capital additions at existing plants are another area where available data suggest a considerable range of experience across utilities. However, the analysis of such additions can be quite complex. First, a considerable portion of the observed variation in the cost of capital additions per unit of capacity can result from environmental or nuclear regulatory decisions affecting specific units that would not be sensitive to the shift to a more competitive regime. Second, capital additions occur at irregularly spaced intervals, and many plants will have no significant capital additions in a particular year.

To address the issue of irregularly spaced capital additions, we focused on average capital additions over a decade rather than additions in a single year. Over the 1985 to 1995 period, reported capital additions at existing power plants averaged approximately $6.3 billion per year, with average additions of $3.1 billion at nuclear plants, $2.6 billion at coal-fired plants, and $0.6 billion at oil and gas steam plants.

For present purposes, the most interesting comparisons can be made within the set of coal plants commissioned after 1965 that were operating without scrubbers or NO_x controls at the end of the sample period, since capital additions at these plants would not reflect the costs of repowering, emissions control requirements, or nuclear regulation. Assuming that the average of the top quartile of reporting units reflects

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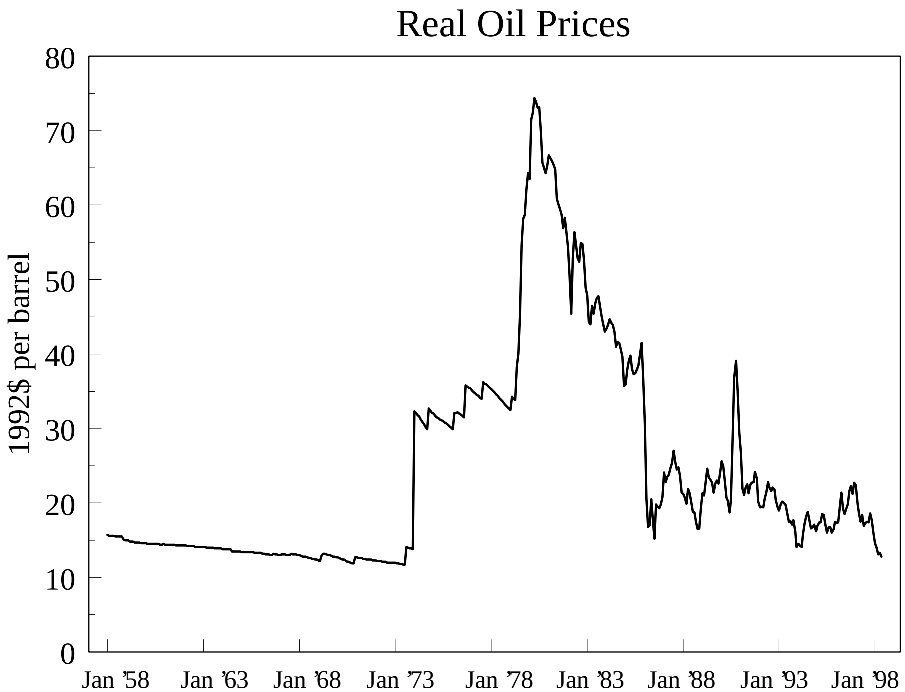
[3] This represents the percentage change in demand resulting from a 1% increase in price.

the standard of performance likely to be typical in competitive markets, annual cost-savings opportunities relative to actual reported costs for capacity additions within this relatively homogeneous subgroup of coal plants are estimated to be $274 million out of $468 million. The application of cartel analysis to the capital additions data for the stratified sample of all plants of all fuel types suggests an overall potential savings of $3.8 billion, but this is likely to be a significant overestimate for reasons outlined above. The real potential for cost-savings in capital additions likely lies in the lower portion of the range of $0.3 to $3.8 billion.

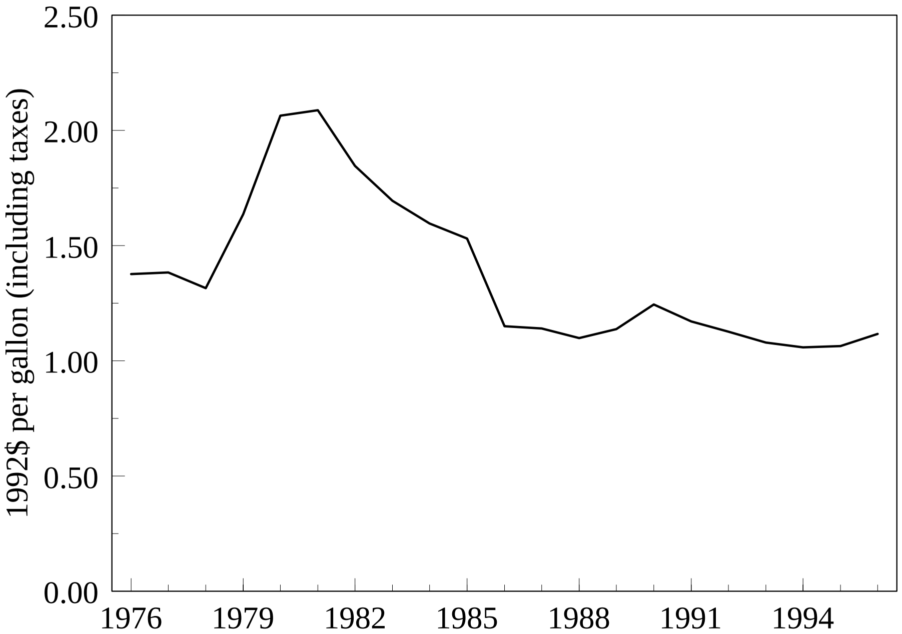
APPENDIX D. HISTORICAL TRENDS IN U.S. ENERGY PRICES

Predicted changes in real energy prices in the illustrative $14/ton and $23/ton permit price scenarios are smaller than the variations observed historically.



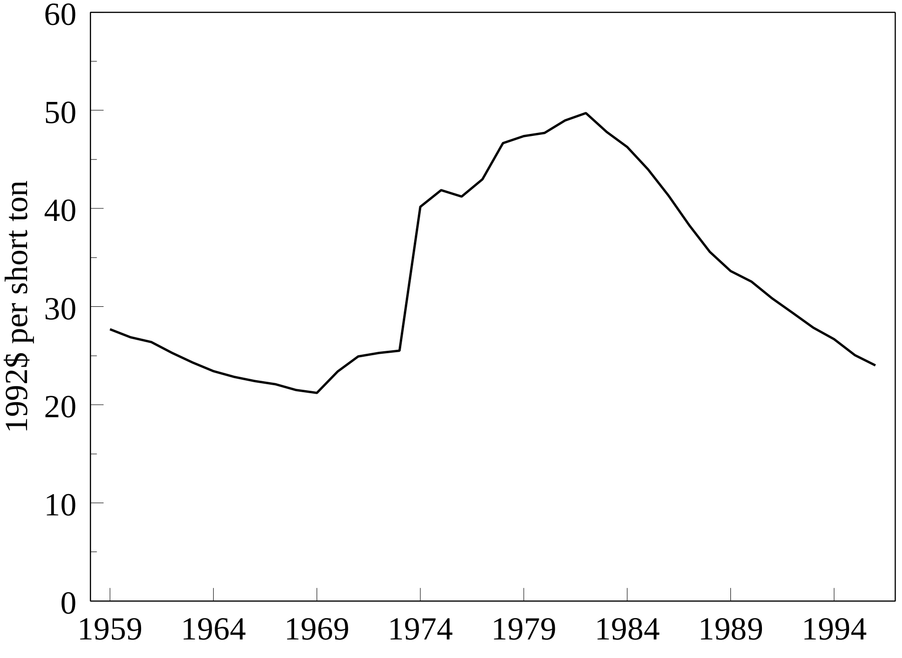
Source: Dow Jones Company.

Real Motor Gasoline Prices



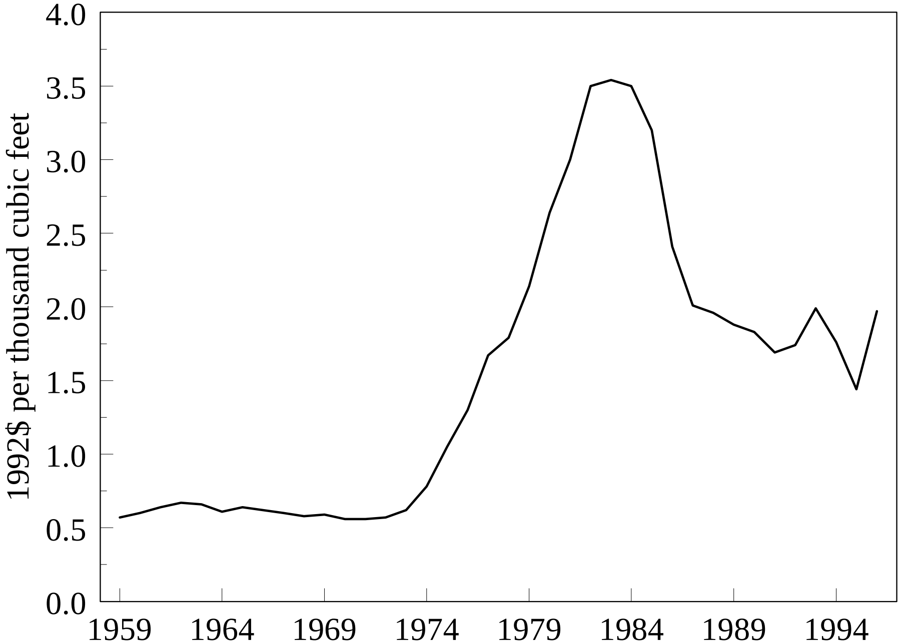
Source: Energy Information Administration 1997c.

Real Coal Prices



Source: Energy Information Administration 1997c.

Real Natural Gas Prices



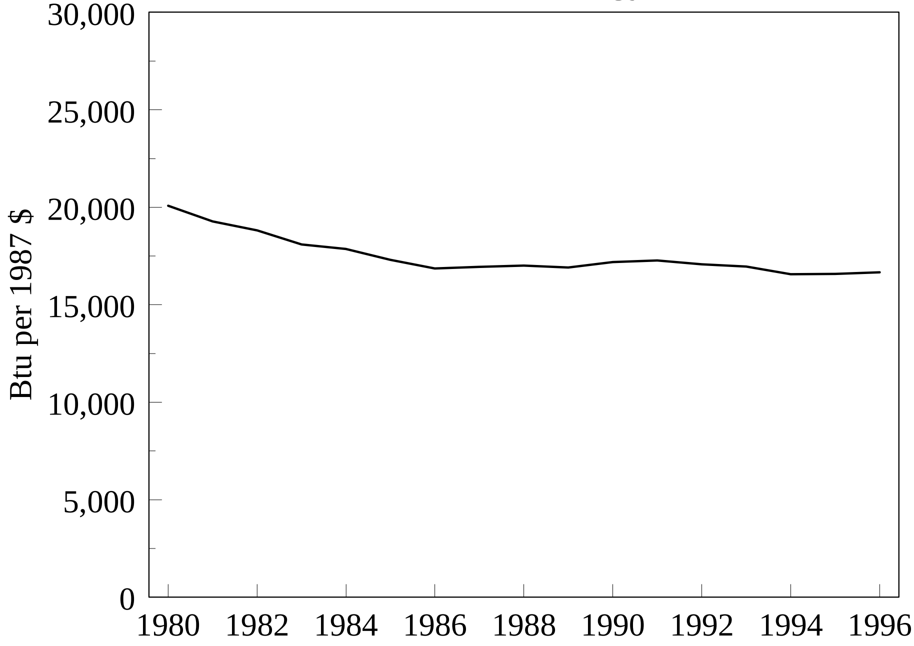
Source: Energy Information Administration 1997c.

APPENDIX E: COUNTRY-SPECIFIC ENERGY AND EMISSIONS DATA

United States
Australia
Canada
China
European Union
India
Japan
Mexico

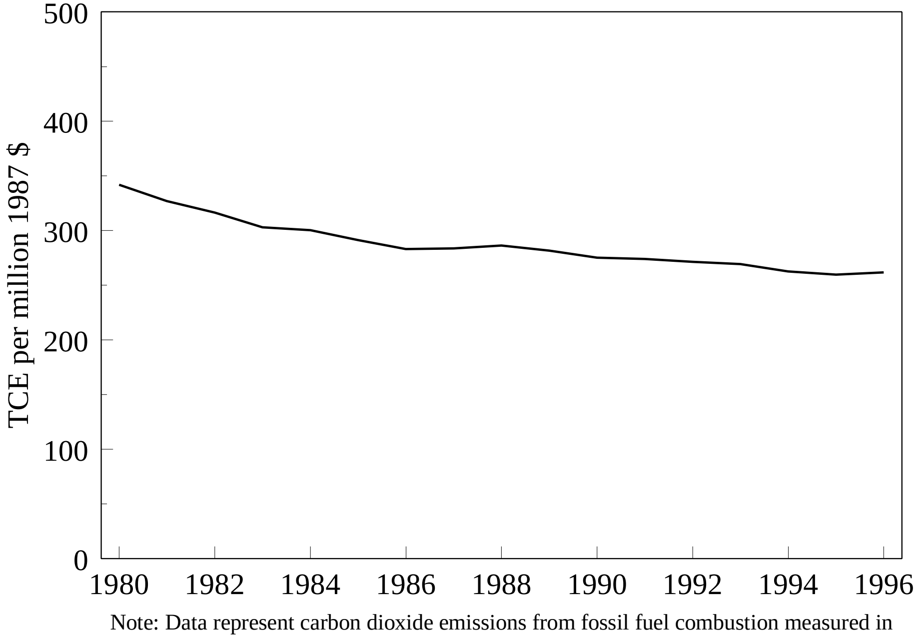
United States

United States Energy/GDP



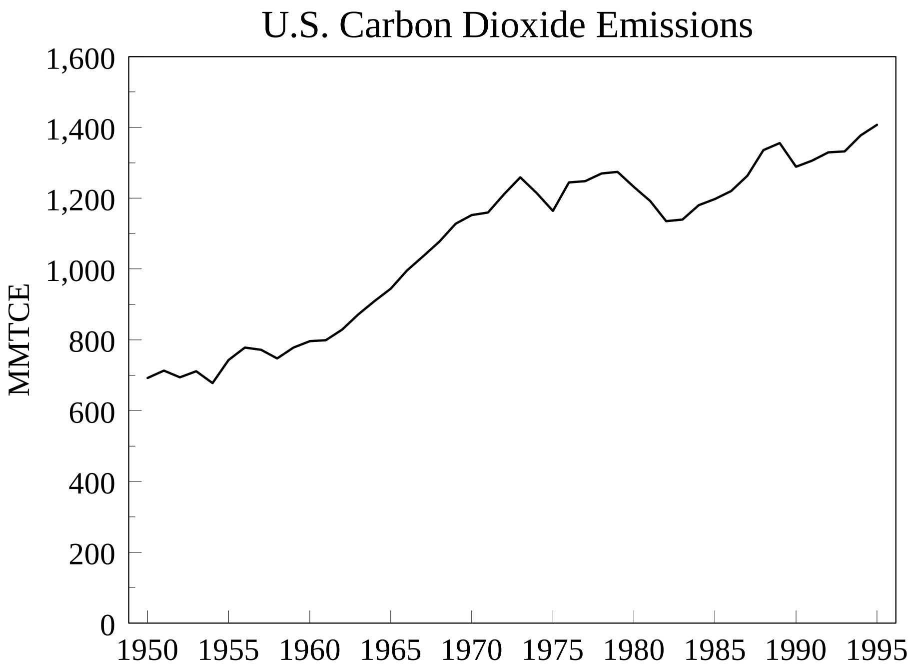
Source: Energy Information Administration 1997c.

United States CO_2/GDP

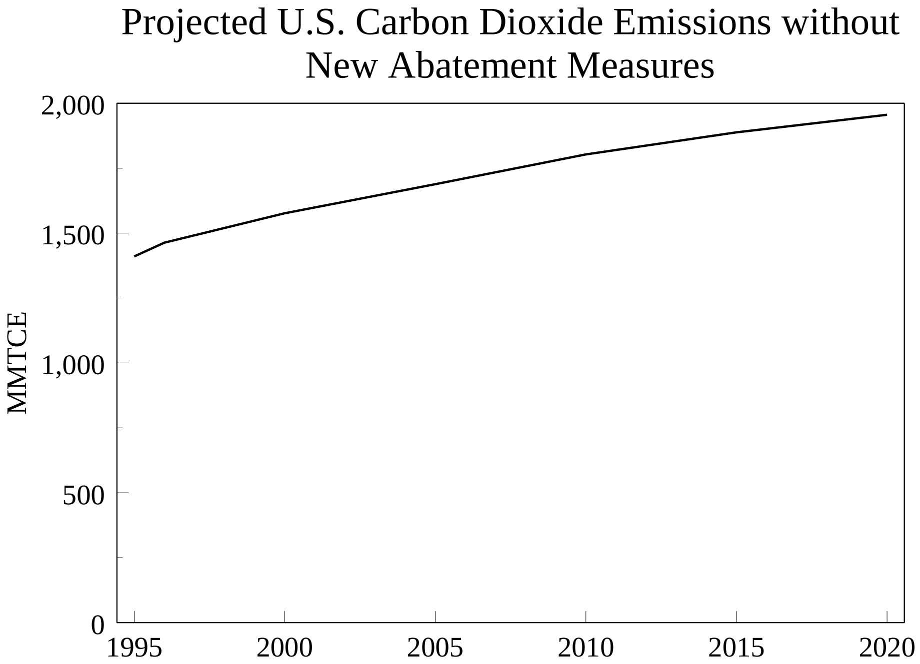


Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

Source: Energy Information Administration 1997c.

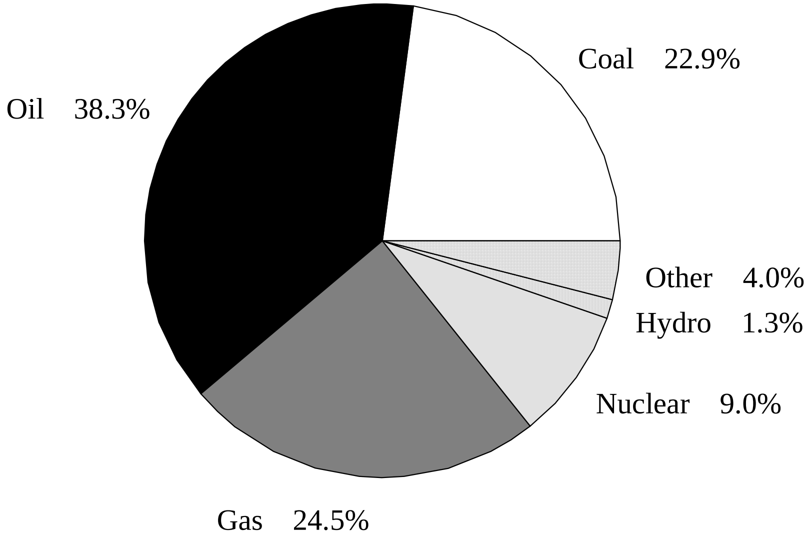


Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.



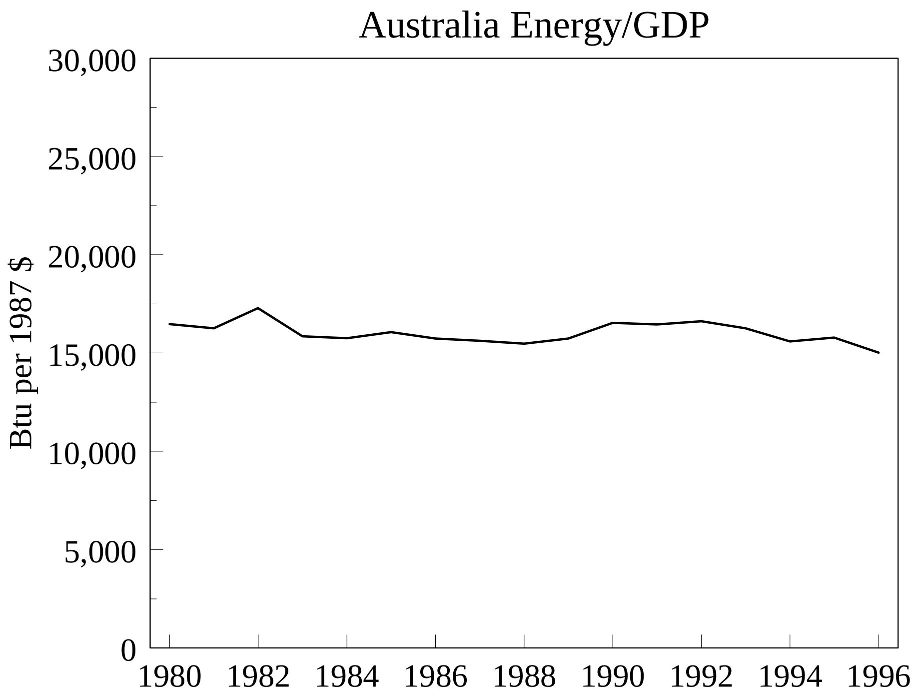
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Energy Information Administration 1998a.

U.S. Total Primary Energy Supply Shares, 1995

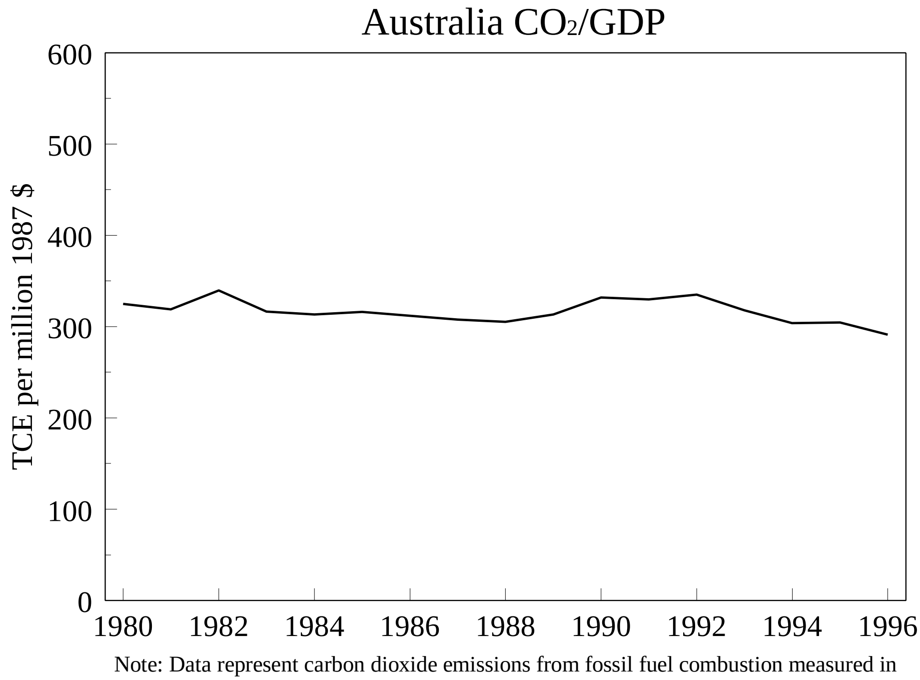


Source: International Energy Agency 1996.

Australia



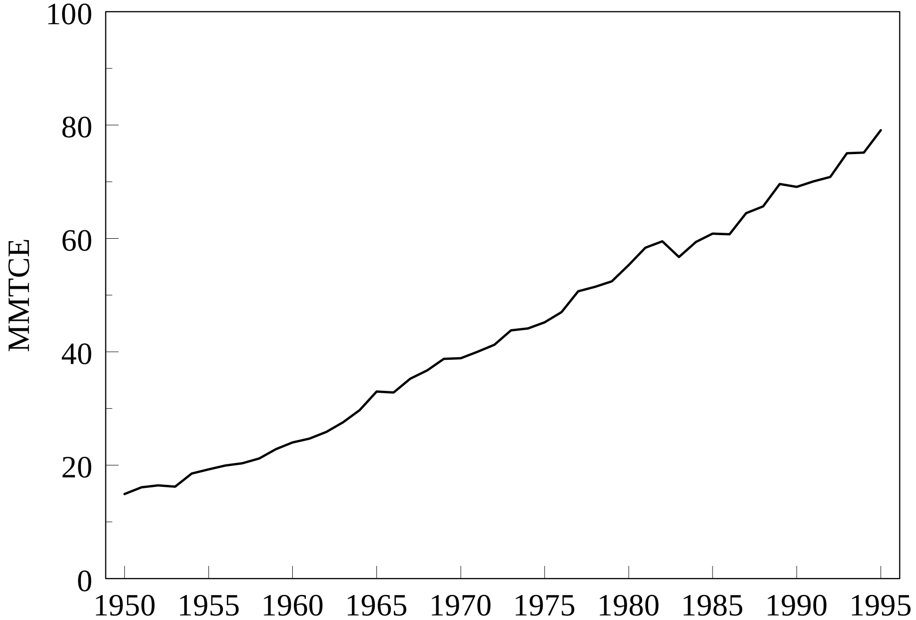
Source: Energy Information Administration 1997c.



Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

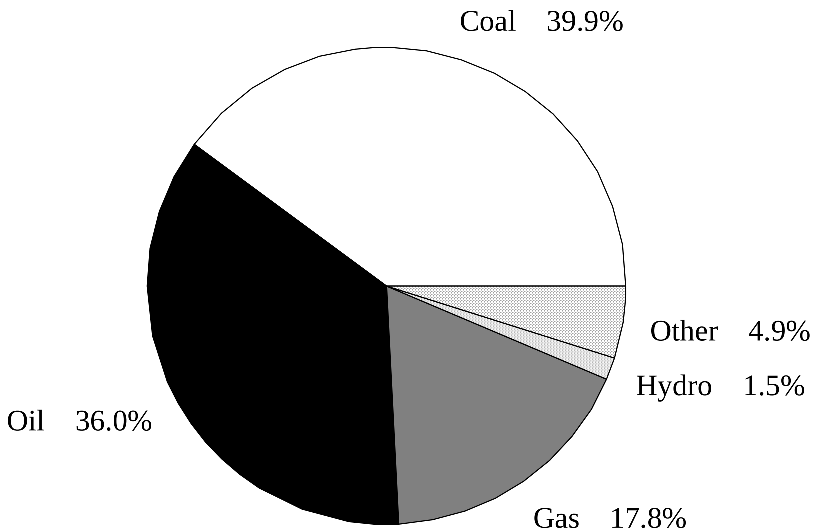
Source: Energy Information Administration 1997c.

Australia Carbon Dioxide Emissions



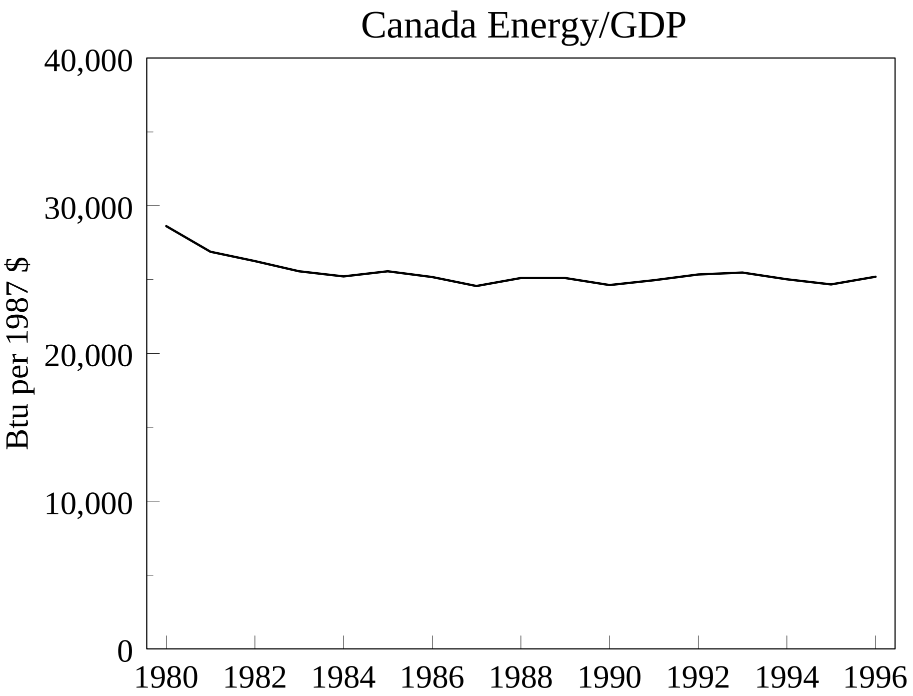
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.

Australia Total Primary Energy Supply Shares, 1995

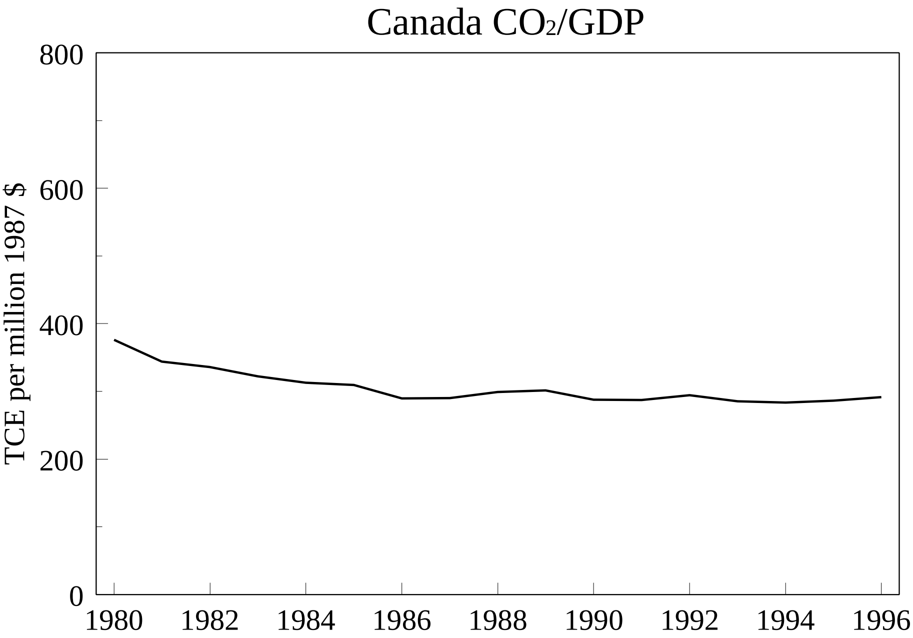


Source: International Energy Agency 1996.

Canada

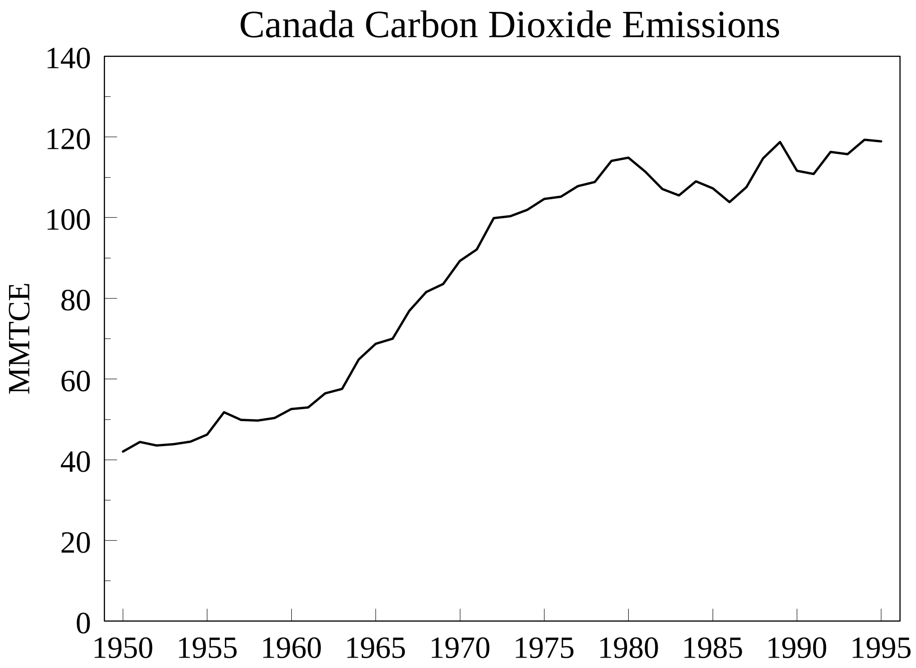


Source: Energy Information Administration 1997c.

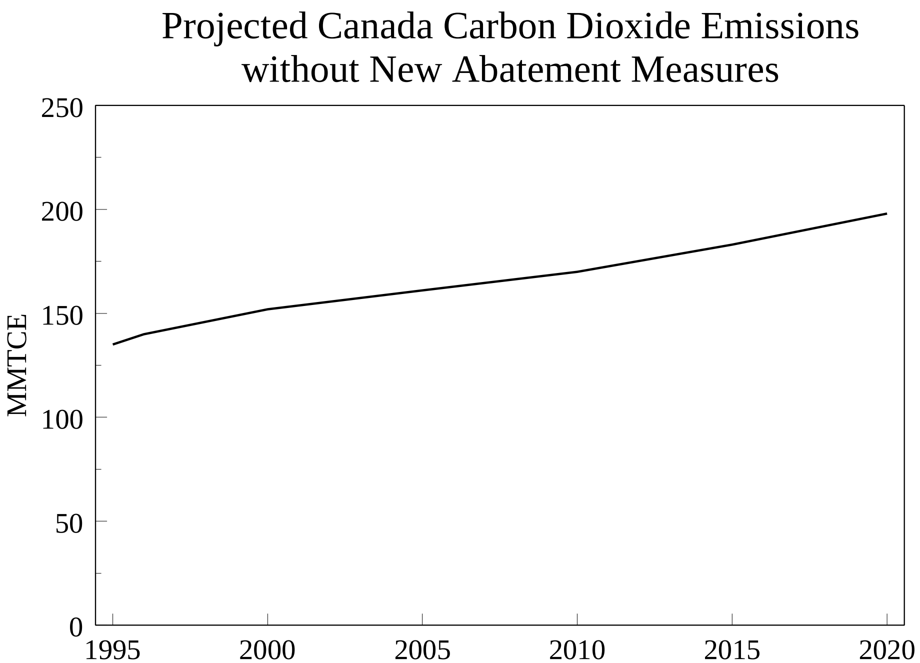


Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

Source: Energy Information Administration 1997c.

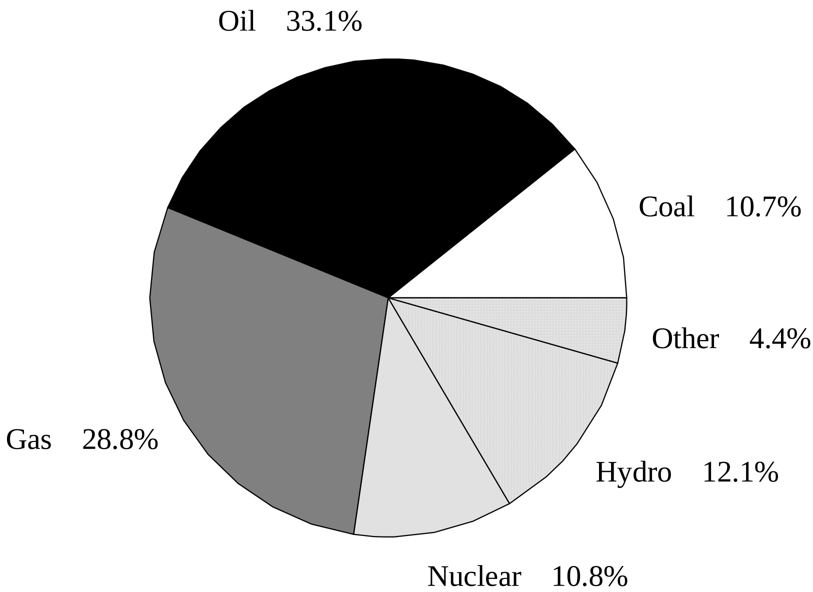


Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.



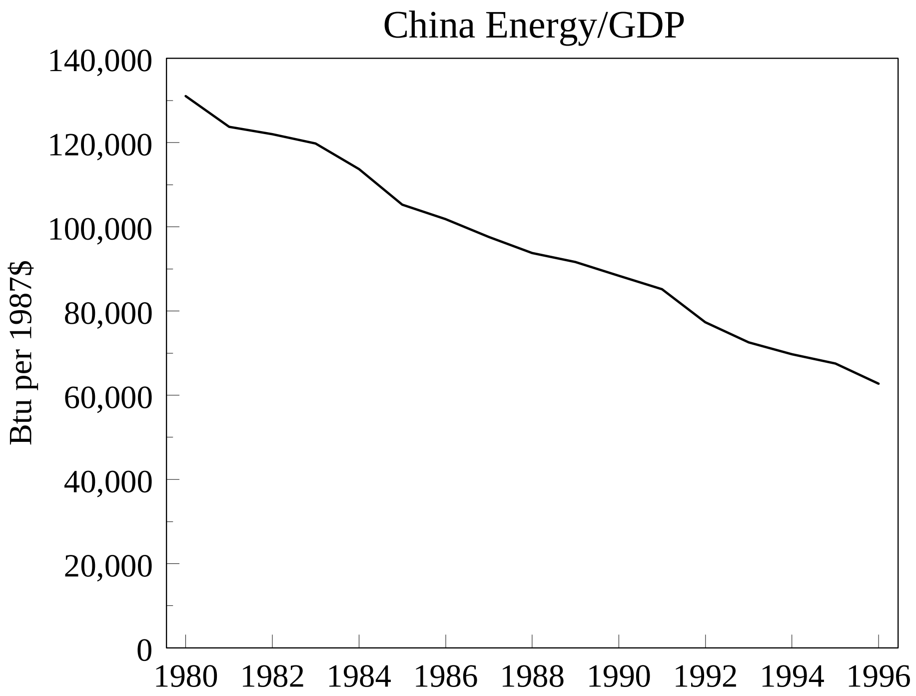
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Energy Information Administration 1998a.

Canada Total Primary Energy Supply Shares, 1995

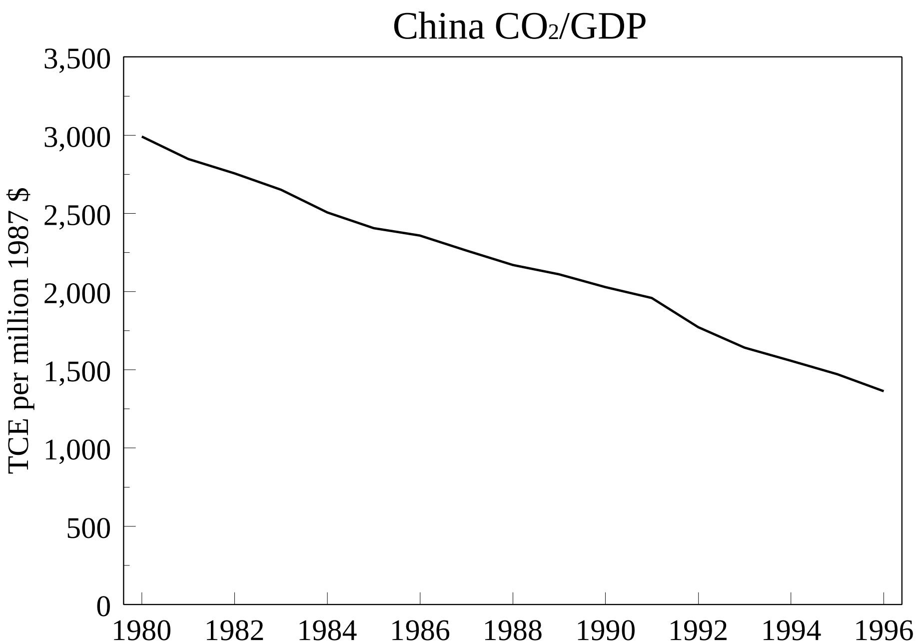


Source: International Energy Agency 1996.

China



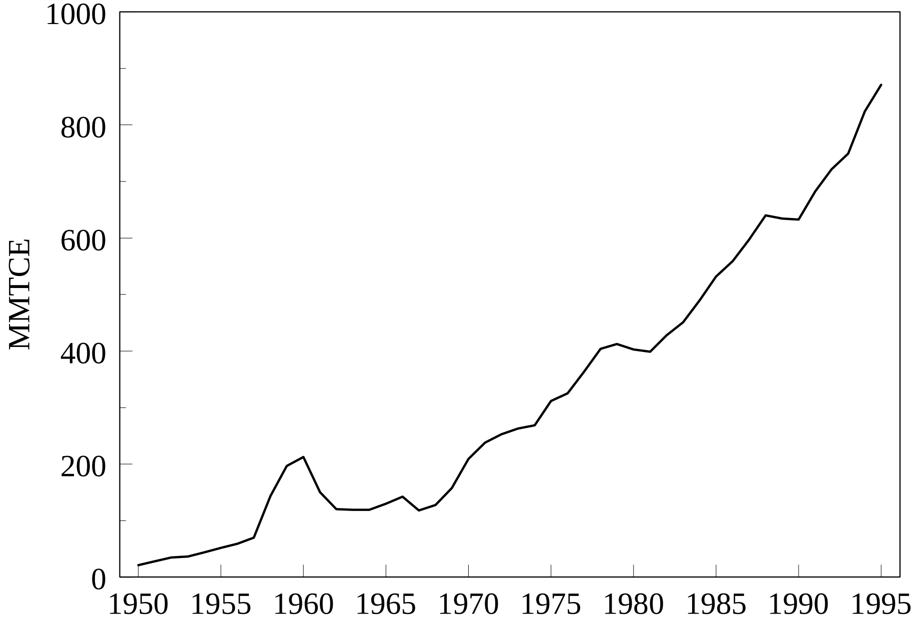
Source: Energy Information Administration 1997c.



Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

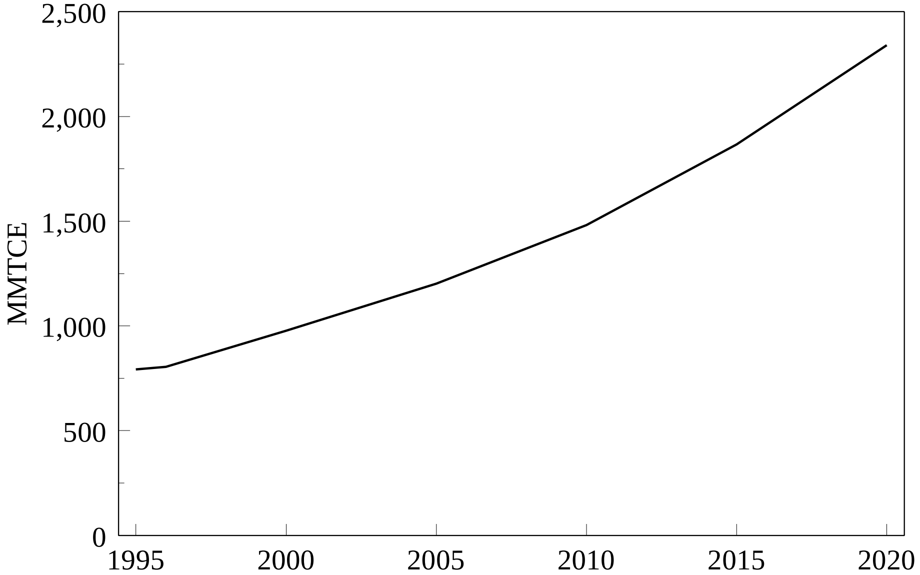
Source: Energy Information Administration 1997c.

China Carbon Dioxide Emissions



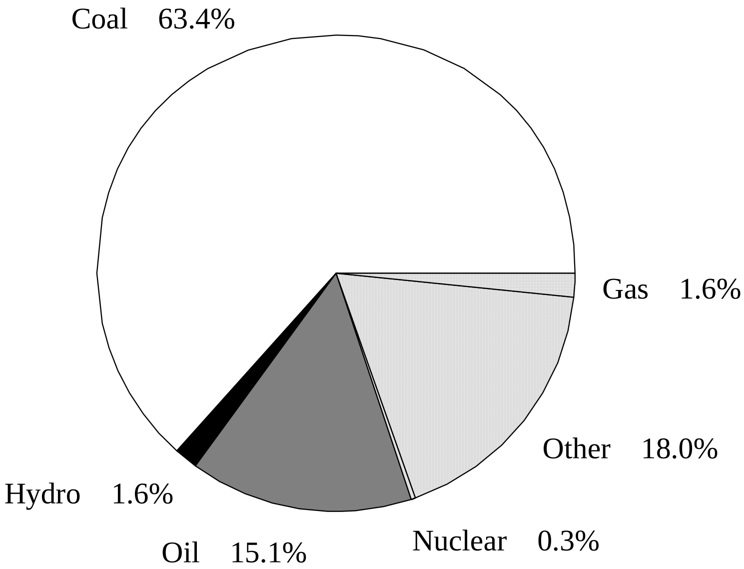
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.

Projected China Carbon Dioxide Emissions without New Abatement Measures



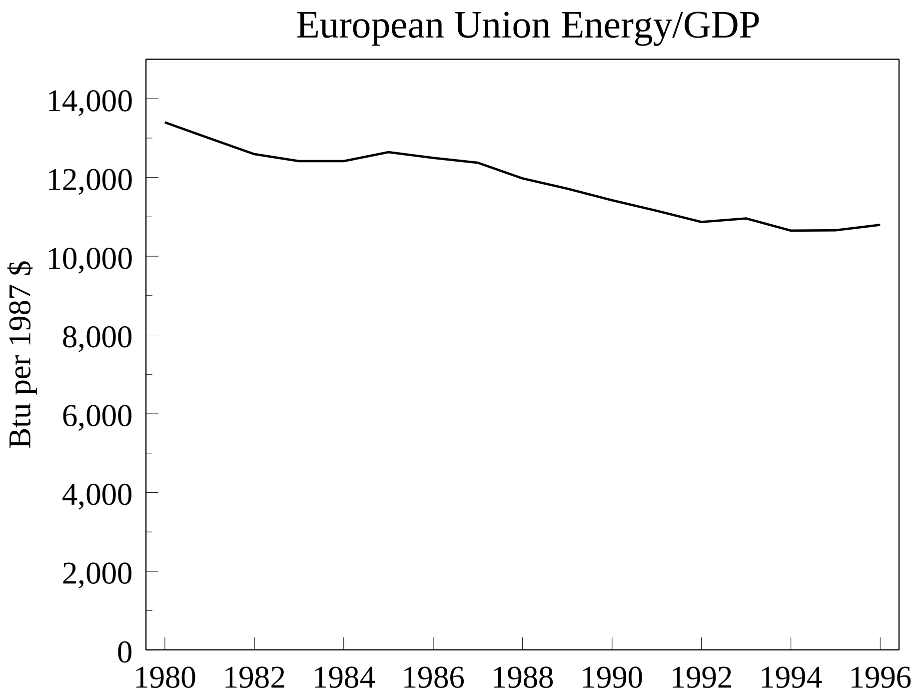
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Energy Information Administration 1998a.

China Total Primary Energy Supply Shares, 1995

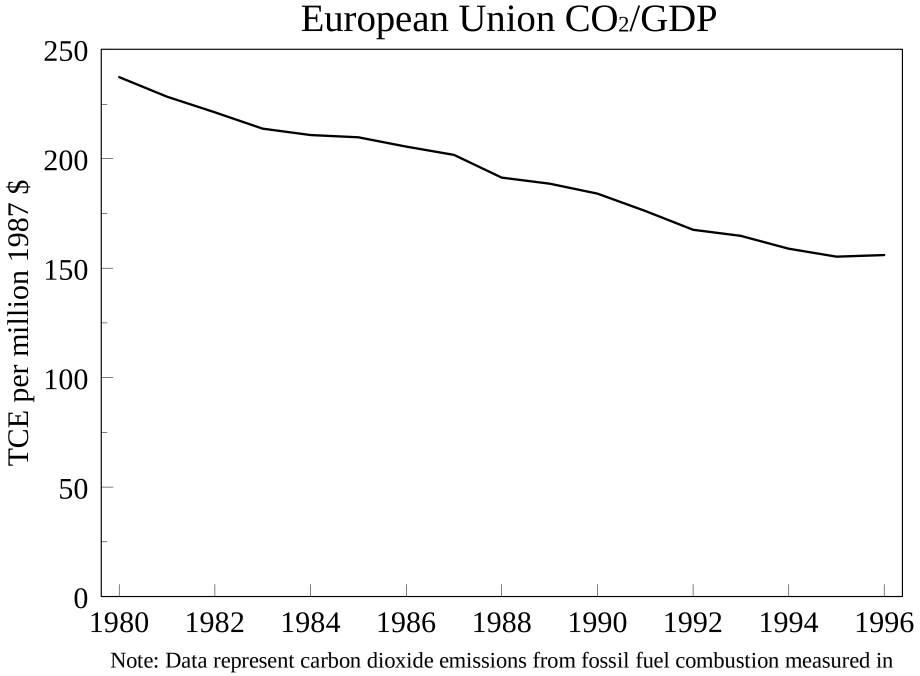


Source: International Energy Agency 1996.

European Union



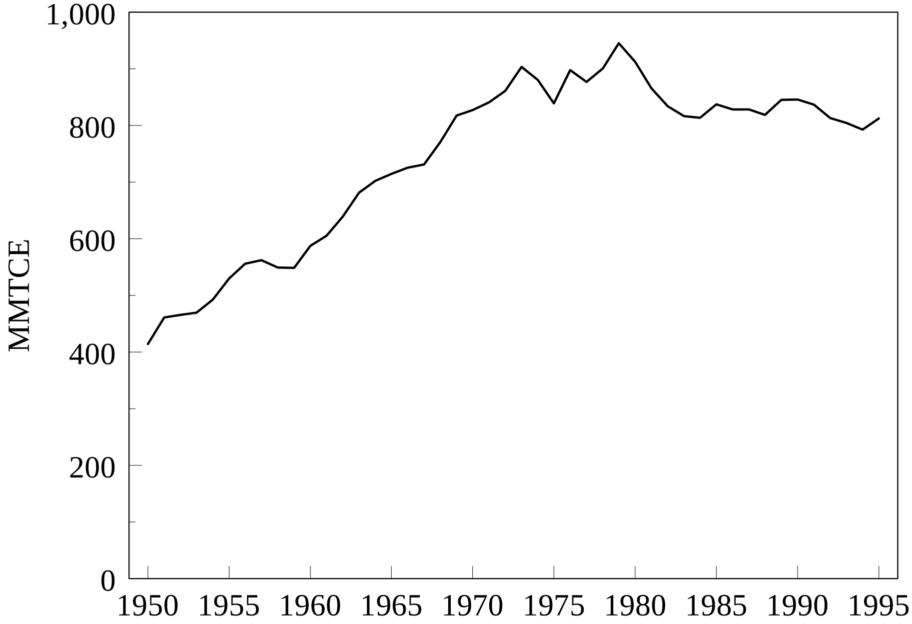
Source: Energy Information Administration 1997c.



Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

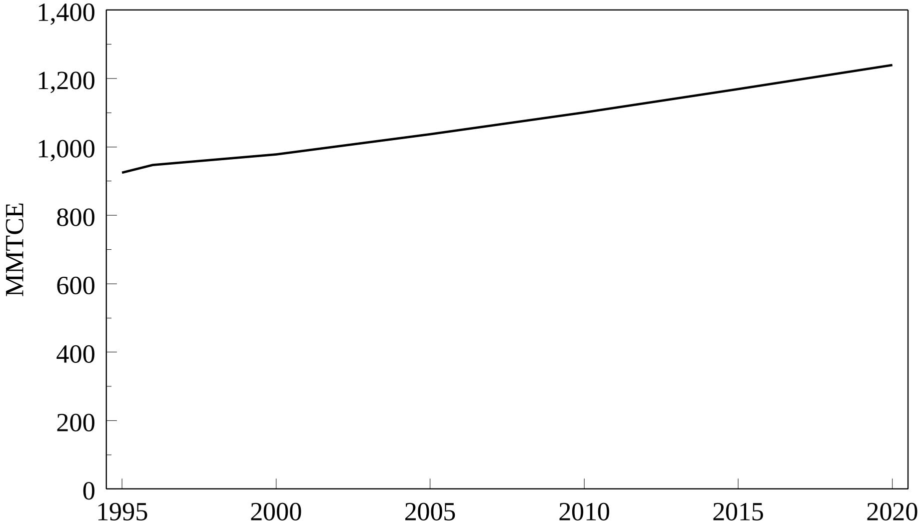
Source: Energy Information Administration 1997c.

E.U. Carbon Dioxide Emissions



Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.

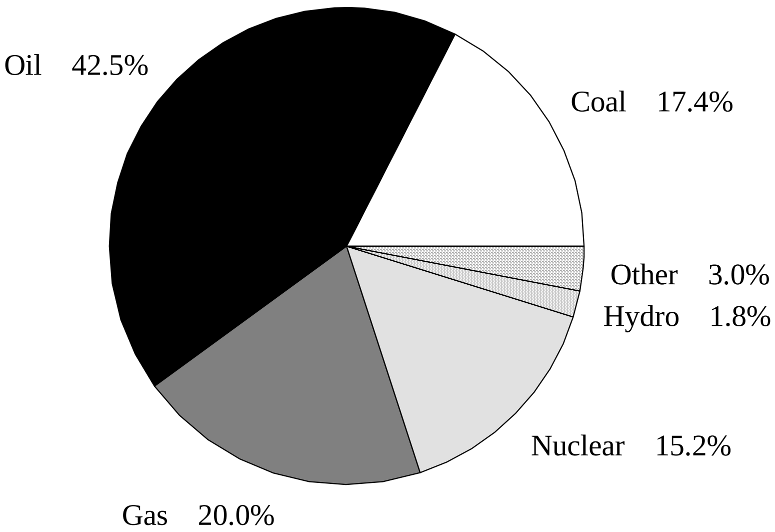
Projected E.U. Carbon Emissions without New Abatement Measures



Notes: Data represent carbon dioxide emissions from fossil fuel combustion. Estimate is for Western Europe. EIA defines Western Europe to include the E.U. and Iceland, Norway, Switzerland, and Turkey.

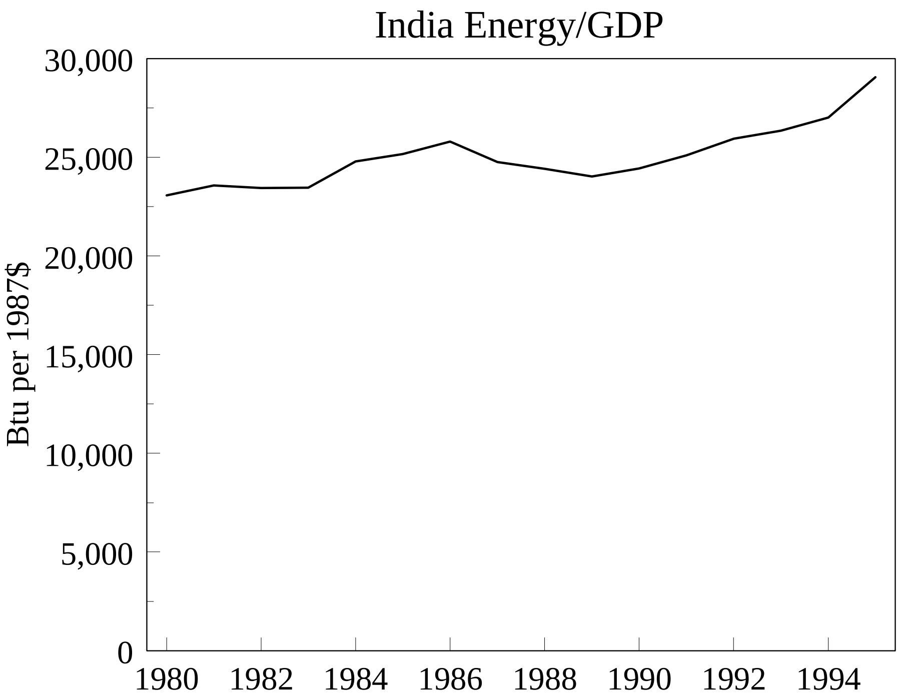
Source: Energy Information Administration 1998a.

E.U. Total Primary Energy Supply Shares, 1995

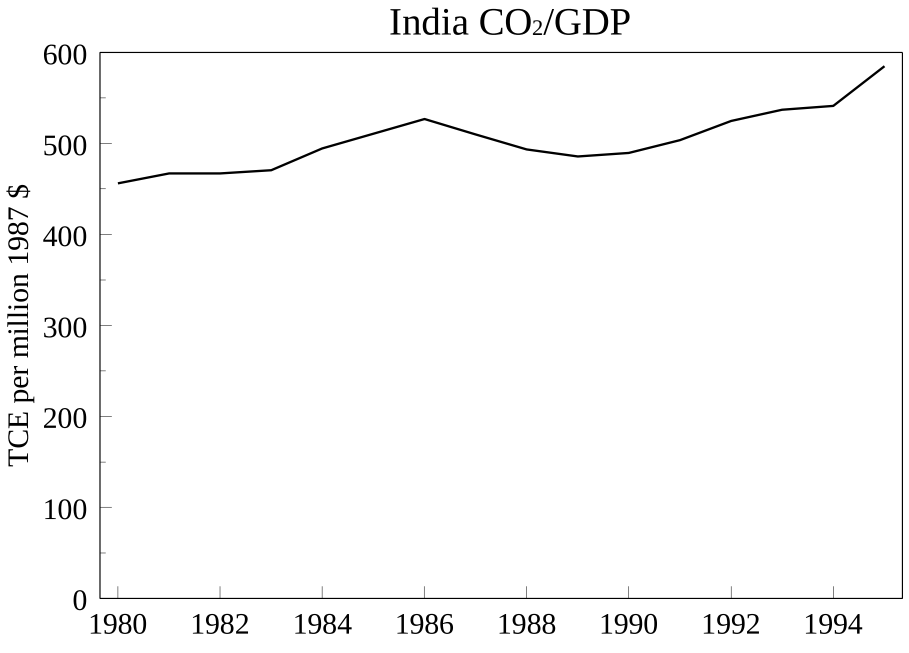


Source: International Energy Agency 1996.

India

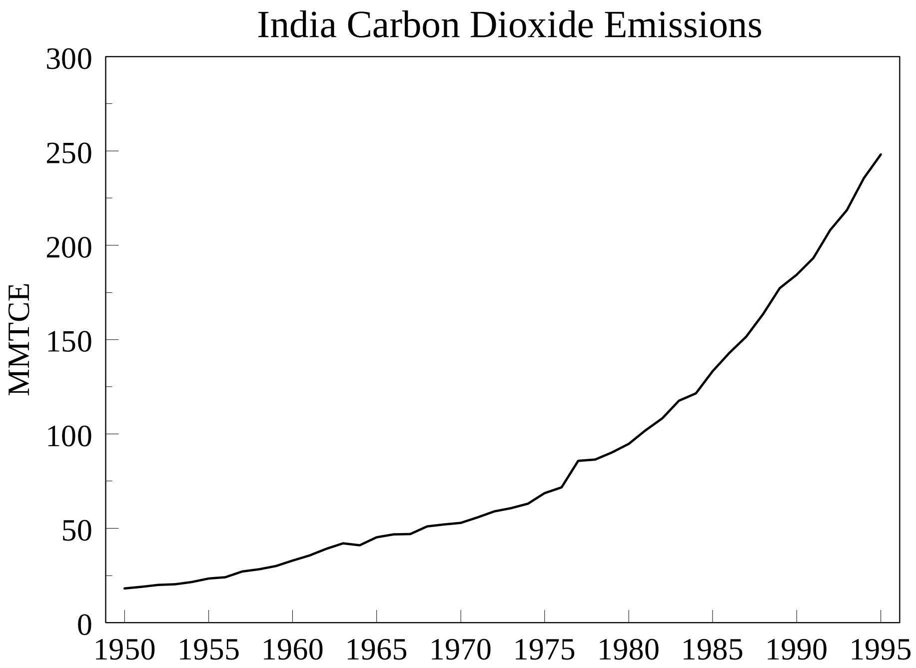


Source: Energy Information Administration 1997c.

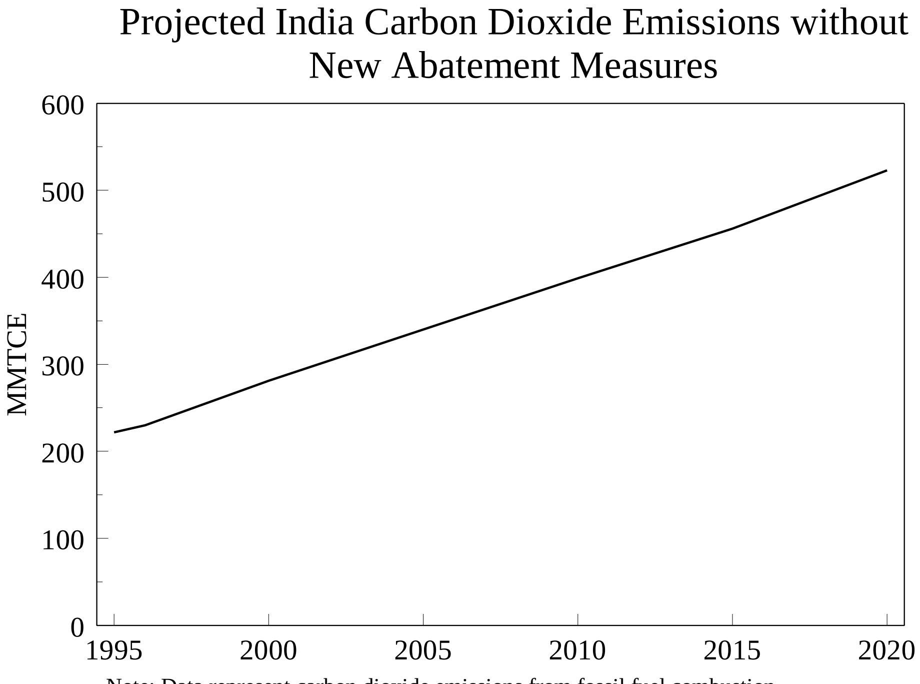


Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

Source: Energy Information Administration 1997c.

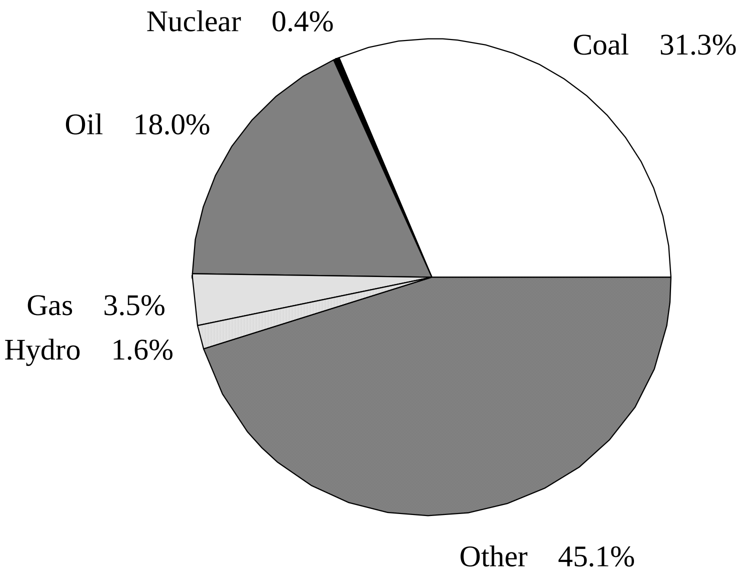


Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.



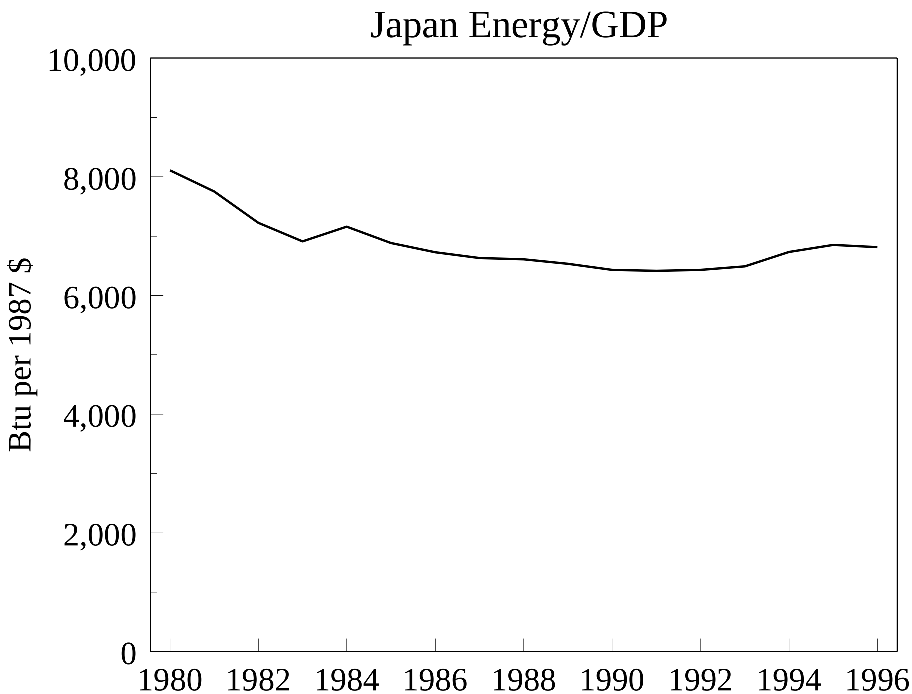
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Energy Information Administration 1998a.

India Total Primary Energy Supply Shares, 1995

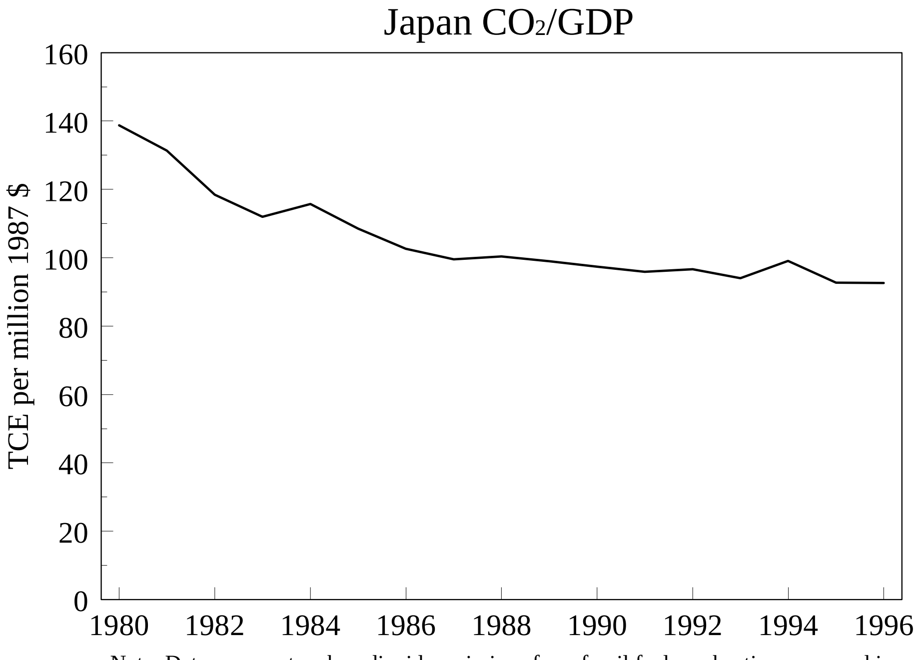


Source: International Energy Agency 1996.

Japan



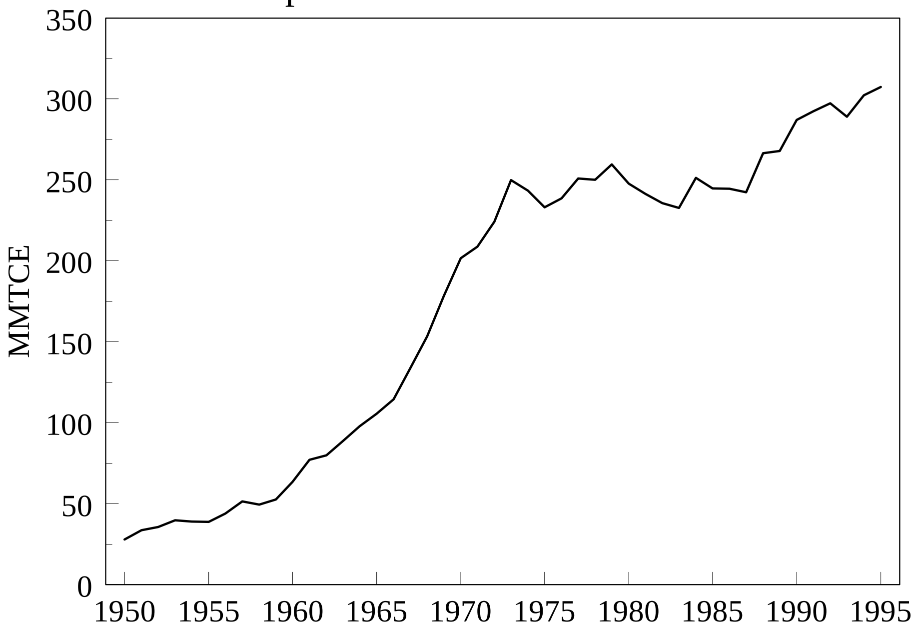
Source: Energy Information Administration 1997c.



Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

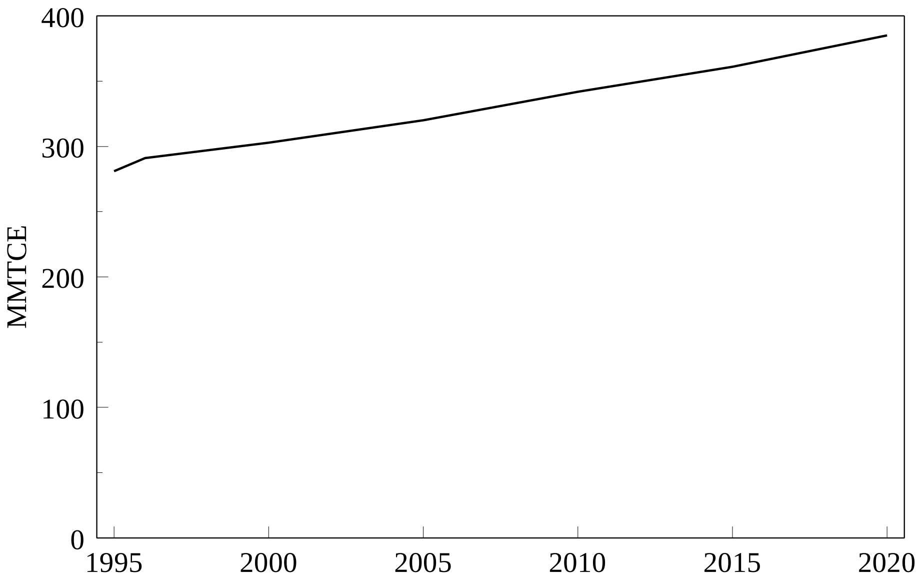
Source: Energy Information Administration 1997c.

Japan Carbon Dioxide Emissions



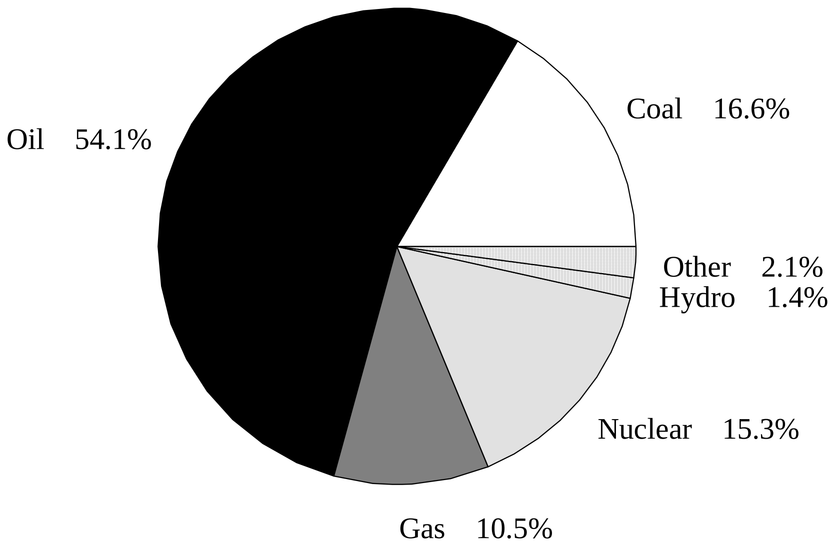
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.

Projected Japan Carbon Emissions without New Abatement Measures



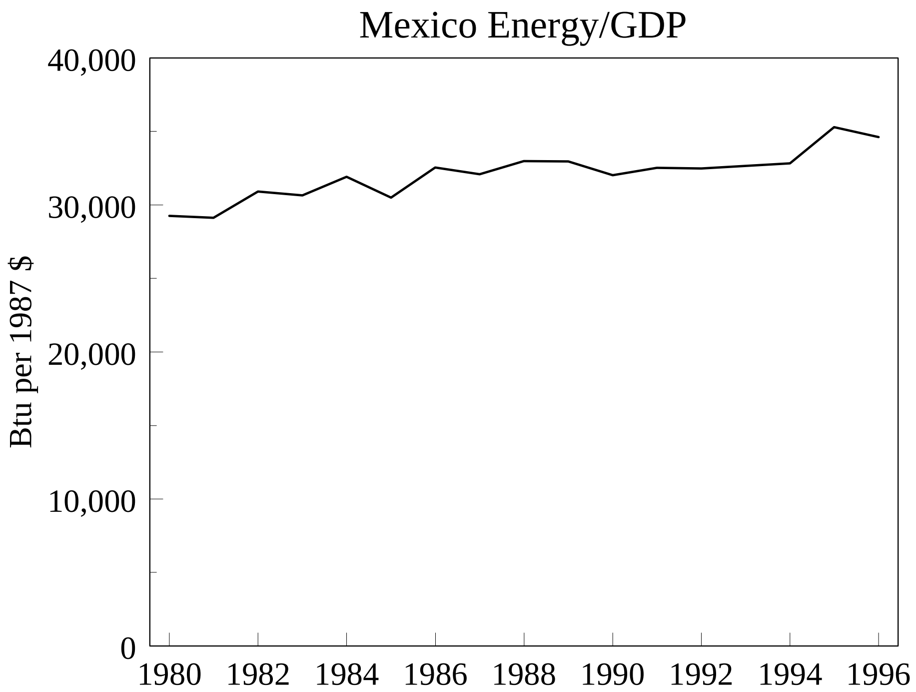
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Energy Information Administration 1998a.

Japan Total Primary Energy Supply Shares, 1995

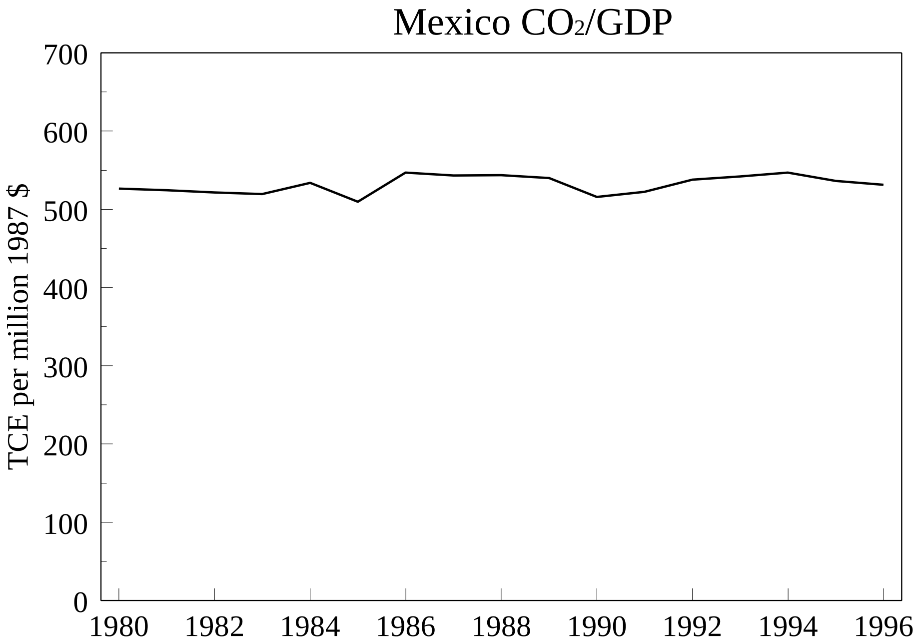


Source: International Energy Agency 1996.

Mexico



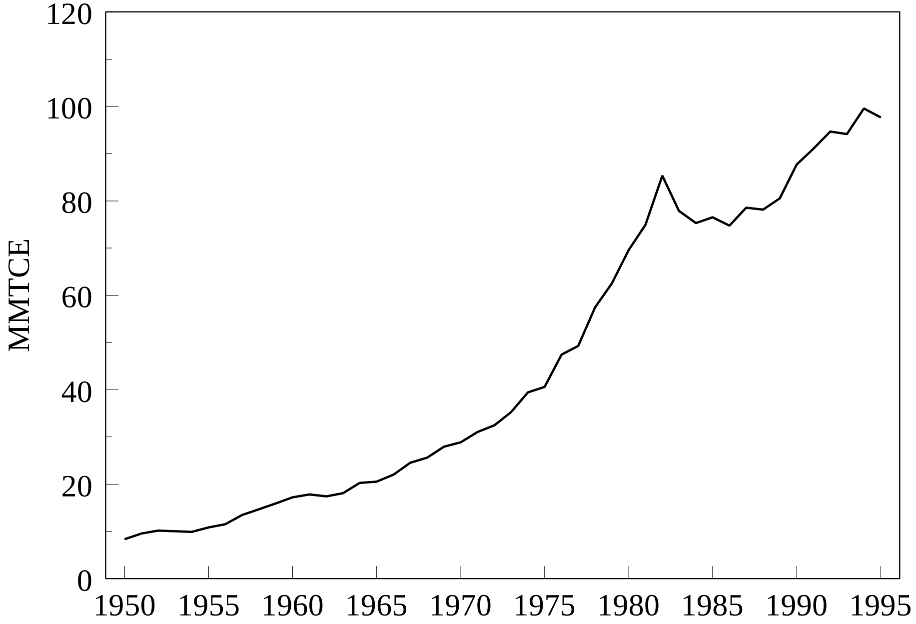
Source: Energy Information Administration 1997c.



Note: Data represent carbon dioxide emissions from fossil fuel combustion measured in carbon equivalent.

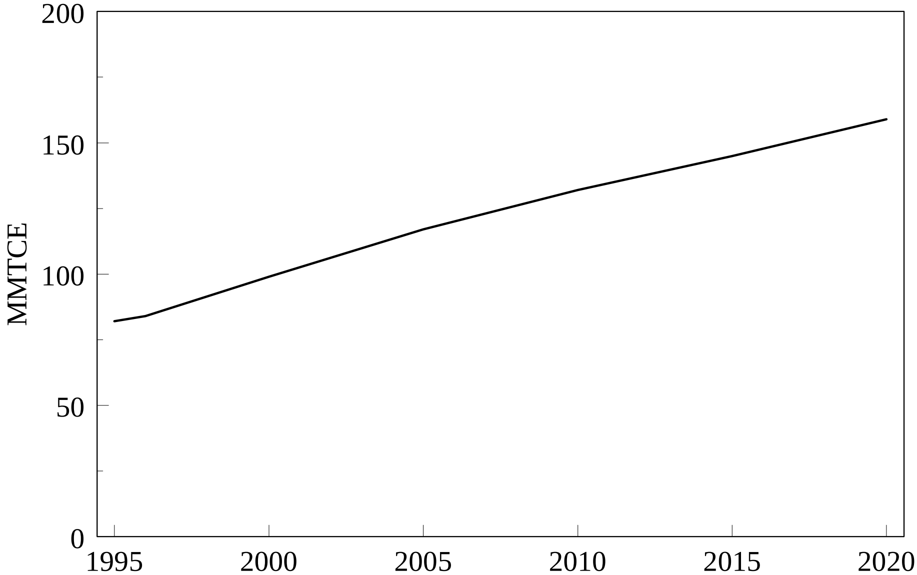
Source: Energy Information Administration 1997c.

Mexico Carbon Dioxide Emissions



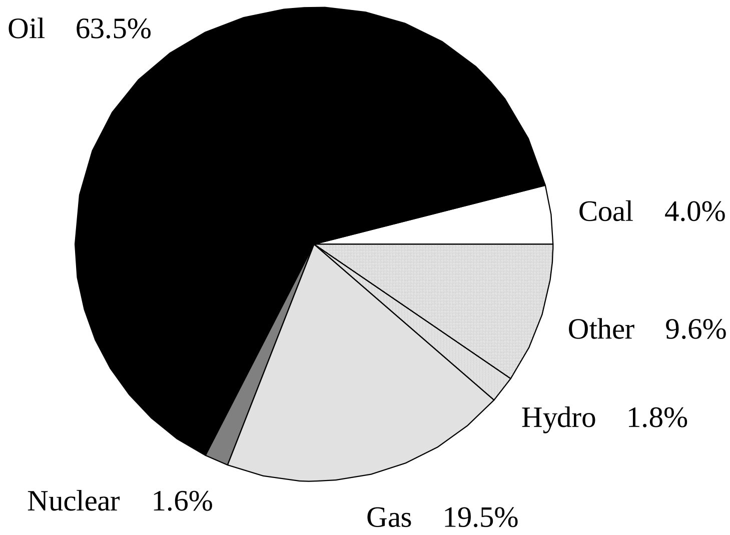
Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Marland and Boden 1998.

Projected Mexico Carbon Dioxide Emissions without New Abatement Measures



Note: Data represent carbon dioxide emissions from fossil fuel combustion.
Source: Energy Information Administration 1998a.

Mexico Total Primary Energy Supply Shares, 1995



Source: International Energy Agency 1996.